# Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado

## *A Critique of PSCo's Distributed Solar Generation Study*

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# Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study

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On May 23, 2013, PSCo Services submitted to the Colorado Public Utilities Commission (Commission) a report on the costs and benefits of distributed solar generation (solar DG or DSG) on the electric system of Public Service Company of Colorado (PSCo). PSCo Services prepared this study (hereafter, the "PSCo Study") in response to Commission Decision No. C09-1223. The Vote Solar Initiative (VSI) retained Crossborder Energy to review the PSCo Study and, if appropriate, to provide alternative analyses based on our firm's experience in conducting similar studies in several other states. VSI used the results of an initial draft of our critique to inform the comments on the PSCo Study which VSI filed, in conjunction with several other parties (the "Joint Solar Parties"), on September 9, 2013. The Alliance for Solar Choice (TASC) has asked us to refine and to update our critique, based on further discovery conducted over the last several months, for submission to the record in the PSCo 2014 Renewable Energy Standard (RES) Plan proceeding (Docket No. 13A-0836E).

## 1. The Benefits of Solar DG

There is a significant, and growing, body of studies on the costs and benefits of solar DG. Many of these studies have been completed in the last several years. The Rocky Mountain Institute (RMI) recently completed a meta-analysis of this body of work in order to assess the common features and most significant differences among such studies.[1] For its meta-analysis, RMI developed a list of the benefits of solar DG typically analyzed in these studies. We have used this list as a starting point to assess PSCo's calculation of the benefits of solar DG. We present this list below, with our conclusion on the adequacy of the PSCo Study's analysis of each benefit listed. We explain in more detail in this report our analysis of each of the benefits that PSCo either did not include or that we view as undervalued.

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[1] Rocky Mountain Institute (RMI), "A Review of Solar PV Benefit and Cost Studies" (July 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

**Table 1:** *Summary of Benefits Assessed in PSCo's DSG Study*

| Benefits to PSCo Ratepayers | Fully Valued | Undervalued | Not Included |
|---|---|---|---|
| Energy | | | |
| Avoided energy (including fuel) | ✓ | | |
| Avoided T&D line losses | ✓ | | |
| Capacity | | | |
| Avoided generation capacity | | ✓ | |
| Avoided T&D capacity and fixed O&M | | ✓ | |
| Grid support services | | | ✓ |
| Financial | | | |
| Fuel Hedging | ✓ | | |
| Avoided RPS or renewables costs | | | ✓ |
| Grid security and resiliency | | | ✓ |
| Environmental | | | |
| Air pollutants ($NO_x$, $SO_x$, PM, & $CO_2$) | | ✓ | |
| Reduced water usage in power production | | | ✓ |
| Avoided land costs for generation or T&D | | | ✓ |
| Societal benefits (not direct ratepayer benefits) | | | |
| Job creation benefits | | | ✓ |
| Economic development, including local taxes | | | ✓ |
| Avoided health impacts | | | ✓ |

### 1.1 Areas of Agreement with the PSCo Study's Assessment of Benefits

We agree with important aspects of the PSCo Study's analysis of solar DG benefits. These include the following:

- **Long-term, 20-year analysis.** The benefits of solar DG should be calculated over a time frame that corresponds to the useful life of a solar DG system, which is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new energy efficiency (EE) program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The PSCo Study uses a 20-year time frame, and reports the results in terms of 20-year levelized $ per MWh values.

- **Broad range of direct benefits.** Generally, PSCo considered a broad range of possible direct benefits of solar DG for non-participating ratepayers. As noted in the chart above and as explained further below, our concerns are principally that PSCo has undervalued a number of these benefits and that it has excluded consideration of broader societal, environmental, and reliability benefits.

- **Avoided energy costs.** PSCo used a production cost model to estimate the long-term avoided energy costs of the 140 MW of solar DG now on its system. The results of this modeling (Figure 5 of the Study) show that the utility's marginal heat rate will gradually decline from about 9 MMBtu/MWh to 7 MMBtu/MWh, consistent with distributed solar generation displacing a blend of an efficient combined-cycle unit (roughly a 7 MMBtu/MWh heat rate) and a less efficient combustion turbine (roughly a 10 MMBtu/MWh heat rate), with combined cycle generation increasingly displaced over time as PSCo adds more efficient gas units. Avoided energy costs based on gas-fired generation make sense given PSCo's plans to retire coal units, convert others to gas, and to add new gas-fired combined cycle units.

- **Avoided line losses.** Solar DG also reduces transmission and distribution (T&D) line losses. It avoids these costs on a marginal basis, by displacing the last, marginal increments of power flowing on the T&D system. Thus, solar DG should be credited with the benefit of reducing marginal, not average, losses over the hours in which solar DG operates. We have reviewed the workpapers for PSCo's calculation of the avoided losses from DSG, and find that the utility reasonably calculates the marginal losses associated with DSG, given the profile of DSG output and PSCo's system losses as a function of load (see PSCo Study, Figure 10 on page 39).

- **Integration costs.** Utilities may incur additional operating costs to integrate intermittent DSG resources into the grid. For example, such costs may arise if solar's variability makes it more difficult for system operators to forecast load net of solar generation, compared to projecting load alone. The PSCo Study includes an estimate of solar integration costs based on a 2009 study of these costs.[2]

### 1.2 Areas of Disagreement with the PSCo Study's Assessment of Benefits

There are six areas in which we have identified issues with PSCo's quantification of the benefits of solar DG, either in the magnitude of the benefits or because the PSCo Study did not consider them. We discuss each of these below, and where appropriate present our own calculations of these benefits.

1. **Avoided Generation Capacity Costs.** PSCo's calculation of the generation capacity costs avoided by solar DG features, in Appendix V, a new study of the Effective Load Carrying Capacity (ELCC) of the solar resources in its service territory. This analysis determines the firm capacity value of a solar DG resource, as a percentage of the resource's nameplate capacity. We have several concerns with this new ELCC analysis, including PSCo's admission to the poor quality of the solar data used,[3] the small sample of projects from which actual output data was obtained,[4] and whether PSCo maintained

[2] PSCo Study, at 41-42.

[3] ELCC Study, at pp. 8-9, and PSCo Study, at pp. 15-16.

[4] For example, the Northern Front Range ELCC results for fixed arrays are based on just 3 projects with 2009 data and 5 projects with data from 2010. There is no actual data for the Southern Front Range for either fixed or tracking arrays, or for fixed systems on the Western Slope. See ELCC Study, at Tables 4 and 5. It is questionable whether this data reflects the geographic diversity of the actual population of installed systems. In addition, the

the necessary time correlation between the load and DG output data used in the ELCC study.[5] More fundamentally, PSCo has not explained why there should be such a dramatic drop in ELCC values compared to its prior 2009 ELCC study which used modeled solar production instead of actual data. Until these concerns are resolved, we recommend use of load duration (LD) data on solar output over the top 50 load hours on the PSCo system as a proxy for the ELCC results. These top 50 hours certainly are critical hours in terms of PSCo's capacity needs, and this data is far more transparent than the ELCC modeling. As shown in Table 2, the use of the LD metric produces capacity values that fall between the results of the two PSCo ELCC studies. Another logical option would be to use solar output as a percentage of the solar AC nameplate capacity from 2 p.m. to 8 p.m. in summer months, which is 44% for the Northern Front Range.[6] Loss-of-Load-Probability (LOLP) data from PSCo's last GRC showed that 99.2% of PSCo's LOLP occurs between these hours.[7]

**Table 2:** *Use of Load Duration Metric as a Compromise between ELCC Results*

| Location | Weight | 2009 ELCC | 2013 ELCC | 2013 LD |
|---|---|---|---|---|
| N. Front Range | | | | |
| Fixed | 79% | 50% | 31% | 40% |
| Tracking | 11% | 59% | 41% | 52% |
| S. Front Range | | | | |
| Fixed | 5% | 54% | 32% | 38% |
| Tracking | 1% | 64% | 40% | 51% |
| San Luis Valley | | | | |
| Fixed | 0% | 51% | 26% | 35% |
| Tracking | 4% | 59% | 47% | 57% |
| Weighted Average | 100% | 52% | 33% | 42% |

Many independent system operators use such load duration data to assess the capacity value of variable resources, and studies have shown that the load duration approach produces similar results to the much more complex, and less transparent, ELCC approach.[8]

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systems sampled are weighted more heavily toward those with a 10 degree tilt than the overall population of systems (see PSCo Study Tables 7, 9 and 10); a more representative weighting of systems with a 30 degree tilt would increase late afternoon output and could improve the ELCC metrics.

5 Table 12 of the PSCo Study shows that summer loads and solar DG output are positively correlated in Colorado. Given this result, one would expect use of actual output and loads would increase ELCCs, compared to 2009 results with modeled (i.e. TMY average) loads and outputs. Thus, the new results in the opposite direction are surprising. Page 6 of the ELCC Study notes that loads and solar output were manipulated to bring them up to 2013, and it is unclear whether this preserved the proper time correlation of this data.

6 Based on data for Boulder from the National Renewable Energy Lab's PVWATTS calculator.

7 See the *Direct Testimony and Exhibits of Scott B. Brockett* in PSCo's last general rate case (Docket No. 09AL-299E), at Exhibit SBB-1 (hereafter, "Brockett GRC Testimony"). Relevant portions of this testimony are included with this critique as Exhibit 802.

8 See North American Electricity Reliability Corporation (NERC), Integration of Variable Generation Task Force, "Accommodating High Levels of Variable Generation" (April 16, 2009), at 39-41, discussing the load duration (capacity factor) approaches used by ISO New England, PJM, NY ISO, CAISO, and several utilities that operate control areas. This NERC report can be found at http://www.nerc.com/files/IVGTF_Report_041609.pdf. In addition, a Solar Electric Power Association (SEPA) report from May of 2008 – T. Hoff , R. Perez, J.P. Ross, and M. Taylor, "Photovoltaic Capacity Valuation Methods," available at

PSCo's estimate of generation capacity costs relies, before 2017, on a bid that PSCo received for short-term capacity, and, after 2017, on data from PSCo's 2011 Electric Resource Plan (2011 ERP) on the annualized capital costs of a combustion turbine (CT). This projection ignores the fact that PSCo's demand-side resources, including solar DG, are providing capacity to its system today, and the utility is relying on the sustained, steady growth of these demand-side resources, including distributed solar, to contribute to meeting its capacity needs before 2017. Without such continued growth in demand-side resources, the utility's need for supply-side resources would be advanced to close to the present. As a result, we believe that it is more accurate to use the full annualized costs of a CT as the value of generating capacity in all years of the analysis. PSCo uses this "proxy" method for valuing the capacity of its DSM programs,[9] and this approach also should be extended to DSG as a demand-side resource. This approach also recognizes the benefit of smaller-scale, short-lead-time resources compared to large central-station units that must be installed in "lumpy" increments and that often produce excess capacity for a number of years once they come on-line.

To determine the generation capacity costs avoided by DSG, the LD capacity value of DSG from Table 2 should be multiplied by the utility's marginal cost of generating capacity. The PSCo Study uses the combustion turbine fixed costs included in the utility's 2011 ERP.[10] We believe that the costs for conventional combined-cycle and combustion turbine units presented in the 2011 ERP are unrealistically low. For example, the 2011 ERP cost for a brownfield 2x1 combined-cycle unit is $652 per kW in 2014 $,[11] which compares to the actual budget of $934 per kW for the Cherokee 2x1 combined-cycle that PSCo is now building.[12] A 2012 report for the Western Electric Coordinating Council (WECC) on the cost of generation technologies showed that PSCo's 2011 ERP CT capital cost ($635 per kW) was at the low end of the range of surveyed costs in the western U.S. for comparable frame CT units.[13] 2013 Energy Information Administration (EIA) data shows capital costs approaching $1,000 per kW in Colorado for conventional CTs,[14] and the NEM cost-benefit studies completed in Arizona earlier this year agreed on a CT capital cost of $1,376 per kW and an annualized CT fixed cost in the range of $160 to $190 per kW-year.[15]

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http://www.solarelectricpower.org/media/8181/sepa-pv-capacity.pdf.
– compared the results from load duration vs. ELCC studies for three diverse utilities (Nevada Power, Rochester G&E, and Portland General Electric) over a range of PV penetration levels, and found that the load duration approach yielded capacity values at or below those derived from the ELCC method.

9 See PSCo response to OCC 3-14, which is included in Exhibit 803.

10 PSCo Study, at 23-24 and Footnote 48.

11 2011 ERP, at Table 2.8-1, with a 15% discount for a brownfield location and escalation to 2014 at 2.5% per year.

12 The current cost estimate for this 569 MW plant is $532 million, or $934 per kW, per the September 20, 2013 semi-annual status report for the new Cherokee plant, as filed in Docket No. 11A-609E.

13 *Cost and Performance Review of Generation Technologies – Recommendations for WECC 10- and 20-Year Study Process* (Energy and Environmental Economics, October 2012), at 23 and Table 11. Available at http://www.nwcouncil.org/media/6867814/E3_GenCapCostReport_finaldraft.pdf .

14 *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (EIA, April 2013), at 6 (Table 1). The conventional CT cost is $992 per kW, including a cost factor of 1.02 for the Rocky Mountain region (Table 4).

15 *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Crossborder, May 2013), at 9-10 and Table 4, available at http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf.

We recommend that PSCo use the more comprehensive and detailed estimate of the capacity-related costs of a CT which the utility presented in its last rate case, and which PSCo used as a measure of its marginal generation capacity costs in designing its current rates. This estimate uses a Frame 7 Combustion Turbine (CT), includes associated electric transmission and gas supply costs, adjusts for energy rents, and adds fixed operations and maintenance costs (O&M) and a 16.3% planning reserve margin.[16]

**Table 3:** *Calculation of Generation Capacity Cost Avoided by Solar DG*

| *Line* | **Component** | **Value** | ***Units*** |
|---|---|---|---|
| *1* | Marginal Generation Capacity Cost (2014 $) | $180.62 | *per kW-year* |
| *2a* | Solar PV Capacity Value, per LD Metric | 42% | |
| *2b* | *Assuming 0.85 kW-AC per kW-DC* | 49% | |
| *3* | Generation Capacity Cost Avoided by DSG | $89.25 | *per kW-year* |
| *4a* | Annual PV Output per kW-DC | 1,500 | *kWh per year* |
| *4b* | *Assuming 0.85 kW-AC per kW-DC* | 1,765 | *kWh per year* |
| *5a* | Generation Capacity Cost Avoided by DSG | $0.051 | *per kWh* |
| *5b* | | $50.57 | *perMWh* |

As shown in Table 3, we use the load duration data to estimate solar PV's capacity value per kW of nameplate capacity and PSCo's more comprehensive estimate of CT costs from its rate case. This produces an avoided generation capacity cost of $50.57 per MWh, higher than the comparable number that PSCo presents in its Study.

2. **Avoided Emissions Costs.** The PSCo Study includes the benefit of the greenhouse gas (GHG) emissions avoided by solar DG, based on the results of the production cost model including the 59 MW and 140 MW levels of DSG and using the 2011 ERP's blend of forecasted $CO_2$ emissions prices from three sources. This blended price is roughly $15.75 per short ton in 2021, escalating at about 7% per year and resulting in a 20-year levelized avoided GHG emissions cost of $5.10 per MWh of solar DG output.

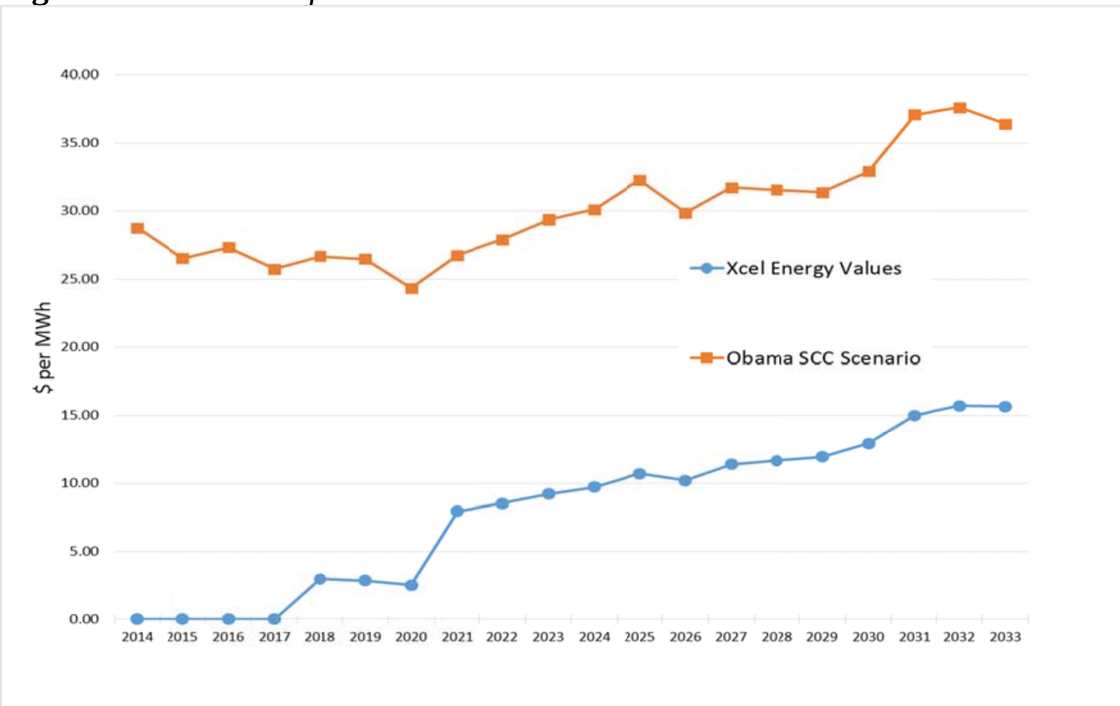
   The federal government has announced that it will prioritize reductions of greenhouse gas (GHG) emissions by focusing on reducing pollution from electric power generation. This regulatory effort to reduce carbon emissions will employ a Social Cost of Carbon (SCC), with a base scenario of a carbon cost of $35 per metric ton $CO_2$ in 2012 (in 2007 $), growing at 2.1% per year plus inflation through 2050.[17] Given this development, we believe that the avoided cost methodology which the PSCo Study employs underestimates the potential for more vigorous regulation of greenhouse gas (GHG) emissions in the near future. Even without a direct price for carbon or government regulation of carbon emissions, in recent years PSCo has taken and is continuing to take substantial and commendable steps to reduce its GHG emissions, steps that are consistent

[16] The details of this calculation are presented in the Brockett GRC Testimony, at pages 12-21 and Exhibit SBB-5. See Exhibit 802. Mr. Brockett calculates the Company's marginal generation capacity costs as $163.63 per kW-year (excluding 7.69% losses), based on the annualized fixed, capacity-related costs of a new combustion turbine (CT). Escalated to 2014 $ at 2.5% per year, this cost in 2014 is $180.62 per kW-year.

[17] See http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf at page 18.

with placing a significant price for $CO_2$ emissions. These include shutting down 1,300 MW of older coal-fired capacity and adding efficient gas generation at the new Cherokee combined-cycle unit. For these reasons, we recommend the use of a $CO_2$ price based on the SCC values, including assigning a cost to $CO_2$ emissions beginning in 2014. When the SCC carbon costs are applied to the avoided $CO_2$ emissions from PSCo's production cost modeling, the levelized avoided emissions costs shown in Table 16 of the PSCo Study increase from $5.10 per MWh to $27.40 per MWh. **Figure 1** compares these two GHG price scenarios, in terms of $ per MWh.

**Figure 1:** *Scenarios for Avoided GHG Emissions Costs*




3. **Avoided Ancillary Service Costs.** The majority of the output of solar DG systems will serve the on-site load of the DG host customer; the rest will run the customer's meter backward when power is exported. As a result, solar DG reduces the loads that PSCo will serve. WECC reliability standards require control area operators to maintain operating reserves (spinning and non-spinning) equal to either the largest single contingency or the sum of 7% of the load served by thermal generation and 5% of the load served by hydro resources, whichever is higher. In discovery, PSCo states that its reserve requirements are based on its largest single contingency in most hours, except in the highest-demand hours when the requirement can be based on loads.[18] As a result, load reductions from solar DG reduce PSCo's requirements to procure operating reserves in only a limited number of high-demand hours. Although DSG may avoid a small amount of ancillary service costs, we have not included them among the benefits in our analysis.

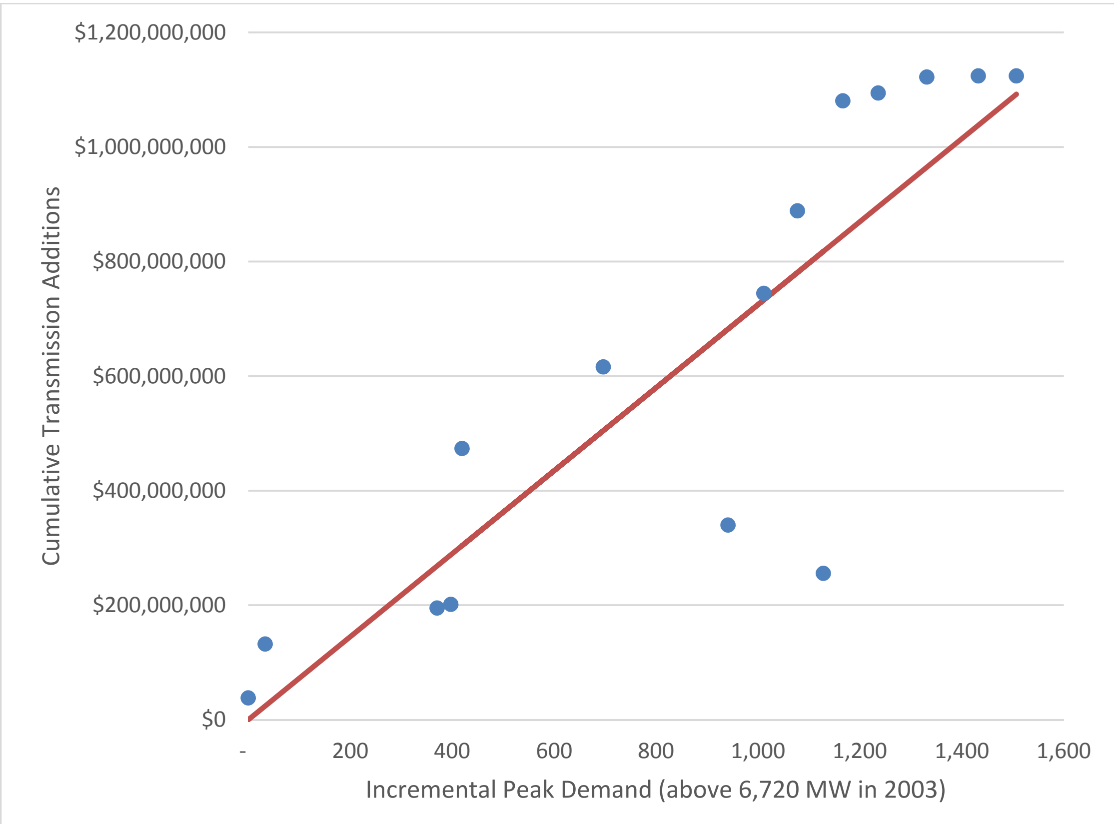
4. **Avoided Transmission Costs.** Most, if not all, solar DG output is either consumed behind the meter or on the distribution system by the neighbors of the DG system, and never touches the transmission system. Solar DG thus clearly reduces the use of the

18 PSCo Response to TASC Data Request 1-15.

transmission system, and will reduce peak demands on the PSCo transmission system even if solar output and peak demand are not perfectly correlated. The PSCo Study fails to consider that peak load reductions from solar DG will allow PSCo to avoid future load-related transmission investments, and considers only the potential for avoided transmission costs associated with (a) transmission interties for avoided generation resources or (b) incidental transmission costs associated with avoided distribution substation capacity.[19]

What is needed is a calculation of how PSCo's costs for transmission capacity change as a function of changes in its system peak demand – i.e. its long-run marginal cost for transmission capacity. We have calculated PSCo's long-term marginal transmission capacity costs using the industry-standard NERA regression method used by many utilities to determine their marginal transmission and distribution capacity costs.[20] **Figure 2** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth.

**Figure 2:** *Calculation of Long-term Marginal Transmission Capacity Costs*




[19] PSCo Study, at 37-38.

[20] The NERA regression model fits cumulative additions in transmission costs to demand growth. The slope of the resulting regression line provides an estimate of the marginal cost of transmission associated with a change in load. The NERA methodology typically uses 10-15 years of historical expenditures on transmission and peak transmission system load, as reported in FERC Form 1, and a five-year forecast of future expenditures and load growth. Crossborder's analysis used PSCo's FERC Form 1 data for the most recent 10 years (2003-2012), and a forecast of transmission project costs over the five years (2013-2017) based on data from the Colorado Coordinated Planning Group's 10-year plan.

We convert the regression slope of $725 per kW using a real economic carrying charge of 7.37% that follows the methodology outlined in the 2011 ERP. Our estimate of annualized marginal transmission costs for PSCo is $54.20 per kW-year, or about $64.20 per kW-year after including a loader for the annual transmission O&M costs (also based on FERC Form 1 data). Finally, we assume that each kW-DC of solar DG capacity reduces PSCo's peak demand by 0.42 kW (from the LD metrics) and convert avoided transmission capacity costs to $ per MWh of solar DG output assuming an average annual output of 1,765 kWh per kW-AC. **Table 4** shows this calculation, which results in $18.00 per MWh of the transmission capacity costs avoided by solar DG.

**Table 4:** *Calculation of Transmission Capacity Costs Avoided by Solar DG*

| *Line* | **Component** | **Value** | ***Units*** |
|---|---|---|---|
| *1* | Marginal Transmission Capacity Cost (2014 $) | $64.20 | *per kW-year* |
| *2a* | Solar PV Capacity Value, per LD Metric | 42% | |
| *2b* | *Assuming 0.85 kW-AC per kW-DC* | 49% | |
| *3* | Transmission Capacity Cost Avoided by DSG | $31.70 | *per kW-year* |
| *4a* | Annual PV Output per kW-DC | 1,500 | *kWh per year* |
| *4b* | *Assuming 0.85 kW-AC per kW-DC* | 1,765 | *kWh per year* |
| *5a* | Generation Capacity Cost Avoided by DSG | $0.018 | *per kWh* |
| *5b* | | $18.00 | *perMWh* |

5. **Avoided Distribution Costs.** The PSCo Study looks only at the small amount of DSG now in place (59 MW), in attempting to assess whether DSG can avoid capacity-related distribution costs. This "bottoms-up" perspective ignores that a range of demand-side resources – both DSM and DSG – will combine, in the long-run, to reduce PSCo's distribution-level demands and thus avoid or defer the need for future distribution upgrades. As with transmission capacity, the utility should look at its long-run marginal cost of distribution capacity, as a function of customer demand. We have used the same regression method we used for transmission to estimate PSCo's long-run load-related marginal distribution capacity costs, based again on FERC Form 1 data. PSCo's marginal distribution capacity costs, including allocations of O&M costs, are $46.10 per kW-year. We note that PSCo has been adding about $175 million per year in distribution additions over the past decade, even though its load growth has been slow due in significant part to the 2008-2010 recession. As a result, load-related growth accounts for just 70% of PSCo's distribution additions over this period. It is possible that our marginal distribution capacity cost understates actual load-related distribution additions, because pre-recession additions probably were premised on higher load growth that failed to materialize after 2008.

Assessing whether DSG avoids distribution capacity costs presents a particular challenge, because distribution substations and circuits show significant variations in when they peak, and often do not peak at the same time as the system as a whole.[21] To address this issue, we followed an approach used by Energy and Environmental Economics (E3) to calculate avoided distribution capacity costs in its recent cost-benefit study of NEM in

[21] See PSCO Study, at 27-28.

California.[22] We obtained hourly load data for 2010 for the 58 distribution substations at which 55% of the existing 59 MW of DSG are connected. For each substation we developed an hourly allocation that measures, in each hour, how close that substation is to its annual peak. The allocation calculates a "peak capacity allocation factor" (PCAF) for each hour in which the substation load is within 10% of the annual peak, using this formula:

PCAF[s][h] = (Load[s][h] – Threshold[s])/Sum[h](Load[s][h] – Threshold[s])

Where
PCAF[s][h] = peak capacity allocation factor for substation s in hour h
Load[s][h] = the load for substation s in hour h
Threshold[s] = 90% of the substation s annual peak load

Sum [h] indicates the summation of all hourly load increments above the threshold.

All hours where the substation load is below 90% of the annual peak are excluded from the calculation. **Figure 3** shows the resulting average PCAF allocation for each hour of the day across all 58 substations, weighted by the amount of DSG installed at each substation. The figure also shows a typical PV output profile for Boulder. As the figure shows, the substation peaks tend to occur later in the day, with the peak in the allocation around 7 p.m., due to substations that largely serve residential load. We apply this allocation to the typical hourly PV output profile for Boulder to determine the portion of marginal distribution capacity costs that DSG can avoid. The result is that DSG can avoid 23% of marginal distribution capacity costs, or 0.6 cents per kWh as shown in **Table 5** below. The remainder of the calculation in Table 5 is similar to Table 4 above.

[22] *California Net Energy Metering Ratepayer Impacts Evaluation* (E3, October 2013), at Appendix C, page C-44. Available at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm .

**Figure 3:** *Substation PCAF Distribution of Loads within 10% of Substation Peak*

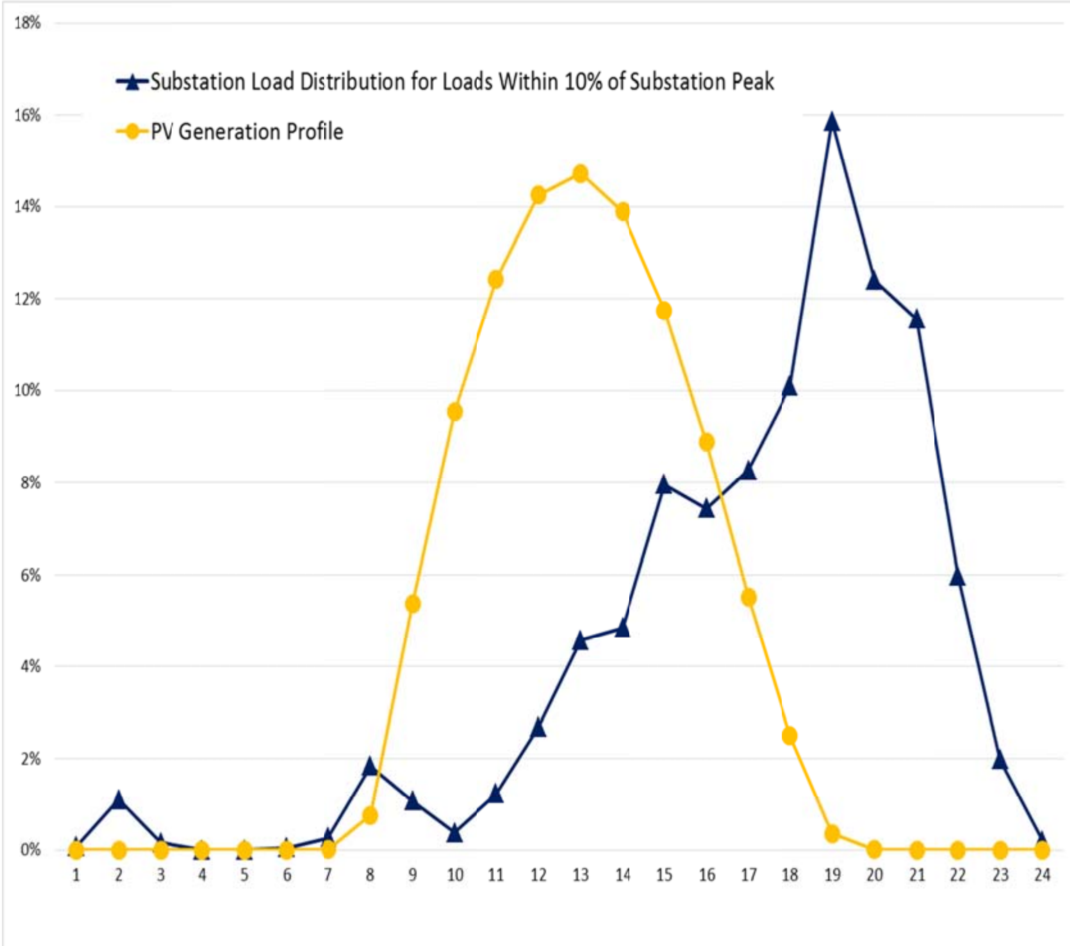



**Table 5:** *Calculation of Distribution Capacity Costs Avoided by Solar DG*

| *Line* | Component | Value | *Units* |
|---|---|---|---|
| *1* | Marginal Distribution Capacity Cost (2014 $) | $46.10 | *per kW-year* |
| *2* | PCAF Factor for Distribution Substations | 23.1% | |
| *3* | Distribution Capacity Cost Avoided by DSG | $10.65 | *per kW-year* |
| *4a* | Annual PV Output per kW-DC | 1,500 | *kWh per year* |
| *4b* | *Assuming 0.85 kW-AC per kW-DC* | 1,765 | *kWh per year* |
| *5a* | Generation Capacity Cost Avoided by DSG | $0.006 | *per kWh* |
| *5b* | | $6.03 | *perMWh* |

6. **Additional Benefits of Renewables.** The avoided cost benefits of solar DG shown in the tables above do not include a number of more difficult-to-quantify benefits of renewable generation which will reduce long-term costs for PSCo ratepayers. These additional benefits include:

- **Price mitigation benefits.** Lower demand for electricity (and for the gas used to produce the marginal kWh of power) has the broad benefit of lowering prices across the gas and electric markets in which PSCo operates.[23] On the electric side, this benefit is difficult to quantify because PSCo does not operate in a market with transparent, hourly locational marginal prices (LMPs) for energy and a transparent market for capacity. In markets with such transparency, the price mitigation benefit, also called the demand reduction induced price effect (DRIPE), has been estimated at 19-25% of combined energy and capacity prices.[24]

- **Grid security.** Renewable DG resources are installed as many small, distributed systems and thus are highly unlikely to fail at the same time. They are also located at the point of end use, and thus reduce the risk of outages due to transmission or distribution system failures. This reduces the economic impacts of power outages for utility ratepayers.

- **Avoided renewables costs.** It is critical that the avoided cost benefits of DSG be calculated assuming that, in the absence of DSG, PSCo would supply the same product received by customers who install DSG. DSG supplies a 100% renewable product, with a renewable content far higher than PSCo is required to provide under the Colorado Renewable Energy Standard (RES). Through the availability of NEM and privately-financed DSG, PSCo avoids the costs to meet some of the customer demand for a 100% renewable product. Accordingly, distributed solar has value in reducing PSCo's costs for additional renewable generation even though the utility has met its RES requirements for a number for years into the future. In this respect, solar DSG customers are similar to PSCo customers who obtain power with up to a 100% renewable content through the utility's Windsource green pricing program, except that PSCo does not incur the Windsource cost premium to serve them.

The first two of these benefits have been calculated separately in at least one study, which estimated these benefits collectively to be from $58 to $92 per MWh (20-year levelized) in several eastern U.S. markets.[25] A metric for the value of a higher penetration of renewable generation on the PSCo system would be the cost premium associated with PSCo's Windsource program in Colorado, currently $21.60 per MWh. PSCo is proposing in this docket to reduce this premium to $15.00 per MWh. Windsource allows customers to be served with a higher penetration of renewable generation than is available through PSCo's system supply, whose renewable content is driven by the Colorado RES requirement.

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23 For example, a Lawrence Berkeley National Lab study has estimated that the consumer gas bill savings associated with increased amounts of renewable energy and energy efficiency, expressed in terms of $ per MWh of renewable energy, range from $7.50 to $20 per MWh. Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005), at ix, http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-56756.pdf.

24 Synapse Energy Economics, "Avoided Energy Supply Costs in New England: 2011 Report" (August 11, 2011), at Exhibit 1-1. Available at http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf .

25 Hoff, Norris, and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2, available at http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

**Table 6** summarizes these potential additional economic, reliability, and environmental benefits. We note that these additional benefits are not necessarily additive. For example, one can argue that ratepayers will obtain the price mitigation benefits of renewables through purchasing a higher penetration of renewable power, and therefore the cost premium for a 100% renewable product provides both benefits.

**Table 6:** *Potential Additional Benefits of DSG*

| Benefit | Magnitude |
|---|---|
| | *20-yr levelized $ per MWh* |
| Price Mitigation | $35 - $69 |
| Grid Security | $22 - $23 |
| Avoided 100% Renewables Costs | $15 - $22* |

** Current value, not a 20-year levelized number.*

We expect that these benefits will reduce long-term direct costs for PSCo ratepayers, even if they are difficult to quantify in the short-run. There are also other "societal" benefits of DSG that will benefit ratepayers indirectly, as citizens. These include expanded in-state employment opportunities, economic development benefits such as increased state and local taxes, and health benefits from a cleaner environment.

We recognize both the long-term direct benefits from Table 6 and the indirect "societal" benefits through a 10% adder to the benefits of DSM. This parallels Colorado's recognition of the "societal" benefits of DSM through the use of a 10% adder to the benefits of DSM in the total resource cost (TRC) test. The benefit-cost comparison presented in this study is a RIM test, not a TRC test; nonetheless, if the results of this test are to be pivotal in the treatment of DSG as a resource for Colorado, the additional direct and societal benefits of DSG should be recognized through the use, at a minimum, of the same 10% adder applied to DSM programs.

### 1.3 Summary of Results

We present in **Table 7** below revised versions of the PSCo Study's summary Table 1 that are based on the re-calculations of the PSCo Study's results presented above.

**Table 7:** *Revised Version of the PSCo Study's Summary Table 1*

| Benefit / (Cost) | Low Gas | | Base Gas | | High Gas | |
|---|---|---|---|---|---|---|
| | *$/MWh* | *%* | *$/MWh* | *%* | *$/MWh* | *%* |
| Avoided Energy Costs | 35.80 | *24%* | 52.10 | *31%* | 76.10 | *39%* |
| Fuel Hedge Value | 6.60 | *4%* | 6.60 | *4%* | 6.60 | *3%* |
| Avoided Emissions | 27.40 | *18%* | 27.40 | *16%* | 27.40 | *14%* |
| Avoided Generation Capacity | 50.60 | *34%* | 50.60 | *30%* | 50.60 | *26%* |
| Avoided Distribution | 6.00 | *4%* | 6.00 | *4%* | 6.00 | *3%* |
| Avoided Transmission | 18.00 | *12%* | 18.00 | *11%* | 18.00 | *9%* |
| Avoided Line Losses | 4.70 | *3%* | 6.20 | *4%* | 8.30 | *4%* |
| (Solar Integration Costs) | (0.50) | | (1.80) | | (4.40) | |
| Subtotal | 148.60 | *100%* | 165.10 | *100%* | 188.60 | *100%* |
| 10% Adder for Societal Benefits | 14.90 | | 16.50 | | 18.90 | |
| **Total Net Benefits / (Costs)** | **163.50** | | **181.60** | | **207.50** | |

## 2. Costs of Solar DG

The primary costs of solar DG are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load. All ratepayers also pay the utility's calculated costs to integrate intermittent solar generation into the grid (which are included above as a deduction to the benefits of solar DG).

PSCo has estimated the long-term, 20-year lost revenues associated with existing solar customers in its Colorado service territory, in its 2014 RES Plan testimony.[26] Based on this data, Table 8 summarizes PSCo's lost revenues by customer class on a 20-year levelized basis using the company's 7.14% discount rate. PSCo's calculation of lost revenues is a simplified calculation based on class average revenues and typical PV system sizes for solar customers in each rate class. Other studies have performed far more granular and detailed calculations of lost revenues, using data on system size and solar customer usage for thousands of individual solar customers, and analyzing the usage and exports from NEM systems on an hourly or sub-hourly basis.[27]

[26] Docket No. 13A-0836E, Testimony of Scott B. Brockett, especially Exhibit SBB-1.

[27] For example, the E3 2013 NEM study referenced in Footnote 19 above used billing data from more than 85,000 NEM customers and performed the analysis of NEM usage and exports on a half-hourly basis. The Crossborder 2013 NEM study for California referenced in Footnote 1 of Exhibit 800 is based on data from 10,000 NEM customers and uses an hourly analysis of NEM usage and exports.

**Table 8:** *PSCo's Lost Revenues by Customer Class*

| Customer Class | Lost Revenues |
|---|---|
| | *20-yr levelized 2014 $ per MWh* |
| Residential (R) | 123.70 |
| Small Commercial (C) | 121.90 |
| Secondary General (SG)* | 103.60 |
| Primary General (PG)* | 108.40 |

** PSCo's SG and PG rates include demand charges that are included in these lost revenue calculations. As solar customers have difficulty avoiding demand charges, the lost revenues for these classes appear to be overstated.*

## 3. Net Benefits or Costs of Solar DG

The net benefits or costs of solar DG are the difference between the benefits summarized in Table 7 and the costs shown in Table 8. These net benefits are summarized in **Table 9**, which shows the net benefits in terms of both 20-year levelized 2014 $ per MWh and in terms of annual dollars. The annual dollar numbers are based on the estimated annual output of the 140 MW of solar DG now installed on the PSCo system.[28]

**Table 9:** *Summary of Net Benefits of Solar DG (2014 $)*

| | Benefits | Costs | Net Benefits or (Costs) | Output | Total |
|---|---|---|---|---|---|
| | *$/kWh* | *$/kWh* | *$/kWh* | *MM kWh/yr* | *MM$/yr* |
| Residential (R) | 0.1816 | 0.1237 | 0.0579 | 66.7 | $3.9 |
| Small Commercial (C) | 0.1816 | 0.1219 | 0.0597 | 9.4 | $0.6 |
| Secondary General (SG) | 0.1816 | 0.1036 | 0.0780 | 97.4 | $7.6 |
| Primary General (PG) | 0.1816 | 0.1084 | 0.0732 | 21.6 | $1.6 |
| **Total** | | | | 195.2 | **$13.6** |

## 4. Conclusion

According to our analysis, DSG provides net benefits to PSCo, and thus to its ratepayers. The annual net benefits of solar DG on the PSCo system are $13.6 million per year.

28 We estimated this output by scaling up the output from the initial 59 MW of solar DG to the full 140 MW, using the data on output by customer class reported in Table 4 of the PSCo Study and the distribution of solar customers by customer class shown in Table 8. We have not included the small number of transmission-level solar customers, because PSCo has not calculated lost revenues for this class.